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Hydrogen UK

Hydrogen Storage: **Delivering on the UK's Energy Needs**

Written by Storage Working Group

Hydrogen UK

Table of Contents

Executive Summary

Recent global events have highlighted the importance of delivering a secure, affordable and resilient energy system as the UK looks to meet its climate change targets and unlock economic growth and green jobs. Ensuring that the system has sufficient energy storage capacity will be critical to energy security and affordability during the energy transition. Hydrogen storage has a key role to play in;

- **Providing long-duration, large-scale storage which will provide greater resilience to volatilities in global energy markets.**
- **Enabling the UK to fully exploit renewables by storing energy when production is high and demand is low thereby reducing curtailment costs.**
- **Allowing the UK to balance intraday and inter-seasonal fluctuations in energy demand and supply**
- **Unlocking the role of hydrogen in sectors such as heat and power generation where hydrogen storage is a pre-requisite.**

The Government's recent Energy Security Strategy acknowledged the vital role hydrogen will play in the UK's future energy mix by increasing our production target to 10GW by 2030. However, building the required storage infrastructure for hydrogen in tandem with the production capacity will be key to ensuring that hydrogen can deliver low carbon affordable energy and economic growth.

Unlocking storage infrastructure investment is urgently needed as **the sector could require 3.4 TWh of large-scale hydrogen storage by 2030, increasing to 9.8 TWh by 2035**. Given the UK's highly favourable geographical characteristics and access to depleted hydrocarbon fields, these requirements can be met but only with the right government support.

To maintain our progress and foster the rapid development of the hydrogen economy, urgent actions are needed. Hydrogen UK, therefore, recommends:

1. **Designing a long-term regulated business model** for large-scale storage no later than 2025.
2. **Launching interim measures** as soon as possible to unlock final investment decisions before the finalisation of the storage business model. In addition to improving investor confidence, it is crucial to provide DEVEX and CAPEX supports as well as introducing a short-term business model.
3. **Creating a strategic planning body** which facilitates the coordination between production, network and storage infrastructure projects and ensures a level playing field for UK business.

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Benefits of Storage in the Energy System

Taking advantage of renewables and reducing their curtailment costs

INTERMITTENCY OF RENEWABLES

Ensuring heat and power during demand and supply fluctuations

SEASONAL HEAT & POWER DEMAND

Strengthening the UK's energy security at times of global volatilities

RESILIENCE AND ENERGY SECURITY

Addressing the intermittency of renewables

Developing large-scale energy storage infrastructure is one of the most effective ways to utilise intermittent renewable energy sources, like solar and wind. Whereas the power grid faces continuous demand, renewables cannot ensure continuous and consistent power generation due to changing weather conditions. Because of solar and wind energy's relatively low load factors, 10 and 29.3% respectively[1], it is highly challenging to increase the share of renewables in the energy mix without posing major risks to energy security. However, this does not mean that renewables do not generate enough electricity. Renewable electricity generation frequently exceeds the circuit capacity and forces producers to switch their facilities off, costing Britain 2.3 TWh and £507 million in 2021[2]. The total curtailment cost is made up of £141 million in payments to renewable producers to shut down their generation and £429 million to alternative plants to compensate for curtailment. To illustrate the volume of curtailed electricity, 2.3 TWh is enough to cover the annual domestic and non-domestic electricity consumption of Manchester[*,3]. The cost of renewable curtailment is expected to grow as the UK Government increases offshore wind capacity to 50 GW and solar capacity to 70GW by 2035[4]. National Grid's system transformation scenario suggests that nearly 23% of wind and solar production will be curtailed in 2035[5]. Therefore, expanding the UK's large-scale and long-duration energy storage capacity would not only balance energy generation when demand is high,

* Using 2020 data

but it would also utilise thousands of gigawatt hours of power which are wasted every year due to limited grid capacity and supply-demand imbalances.

Balancing the varying heat and power demand

Natural gas storage has been widely used in the UK since the mid-1980s to balance the seasonally fluctuating heating requirements of domestic and commercial buildings. On cold winter days, when the heating demand can reach 170 GW[6], and the hourly ramp rate can be as high as 120GW[7], electricity generation is incapable of coping with the demand. The extent of seasonal fluctuation is illustrated by the significant increase in domestic gas consumption from a summer daily average of 0.4 TWh to 3.5 TWh in the cold winter days[8]. GB households, therefore, have been using natural gas or heating oil during winter as these fuels can be easily stored inter-seasonally and can satisfy large and unexpected rises in consumption. To meet peak electricity demands when power generation is not sufficient, Combined Cycle Gas Turbines (CCGT) are ramped up in the energy system as they are generally more flexible than coal and nuclear power plants[9]. CCGTs run on natural gas to generate electricity throughout the year, with the technology being able to capture the waste heat. However, due to high carbon intensity of these fossil fuels, either they have to be replaced by a low-carbon fuel alternative or electricity storage capacity has to be improved dramatically if the UK is to meet its 2050 emission targets.

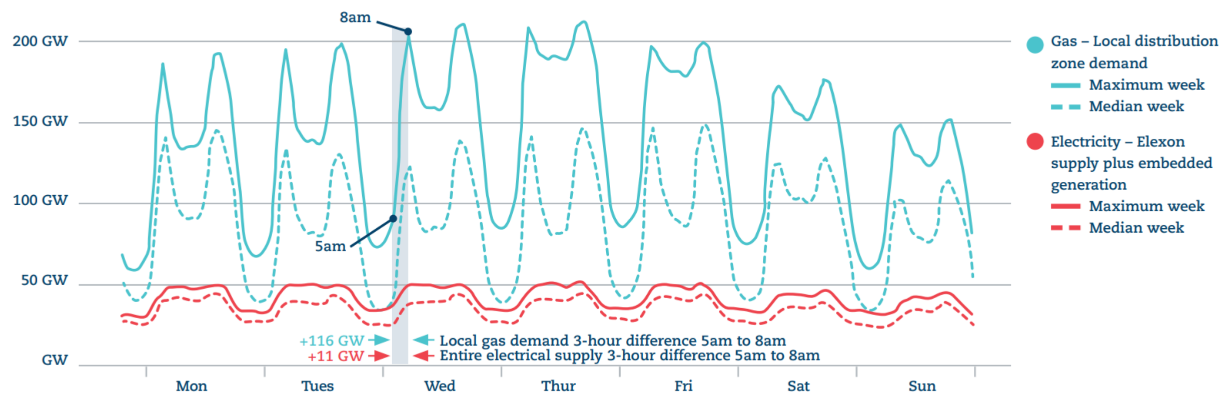

Figure 1: Local gas demand and electrical system supply in median and maximum demand weeks. Electrical supply data is provided by Elexon and National Grid

Source: UKERC 2020

Strengthening energy security and resilience

The UK has one of the highest dependencies on natural gas in Europe[10], and is therefore relatively vulnerable to the volatilities of the global energy market. This is intensified by low natural gas storage capacity. The UK only supports approximately 5% of Germany's capacity[11], and has been largely diverging from European household energy price trends since the beginning of the energy crisis[12, 13]. Resilience to demand and supply side shocks, such as particularly cold winters or power outages, is critical from an energy security point of view. Therefore, increasing large-scale energy storage would not only unlock more long-term contract opportunities, with generally lower prices, but it would also alleviate the UK's import dependence[14].

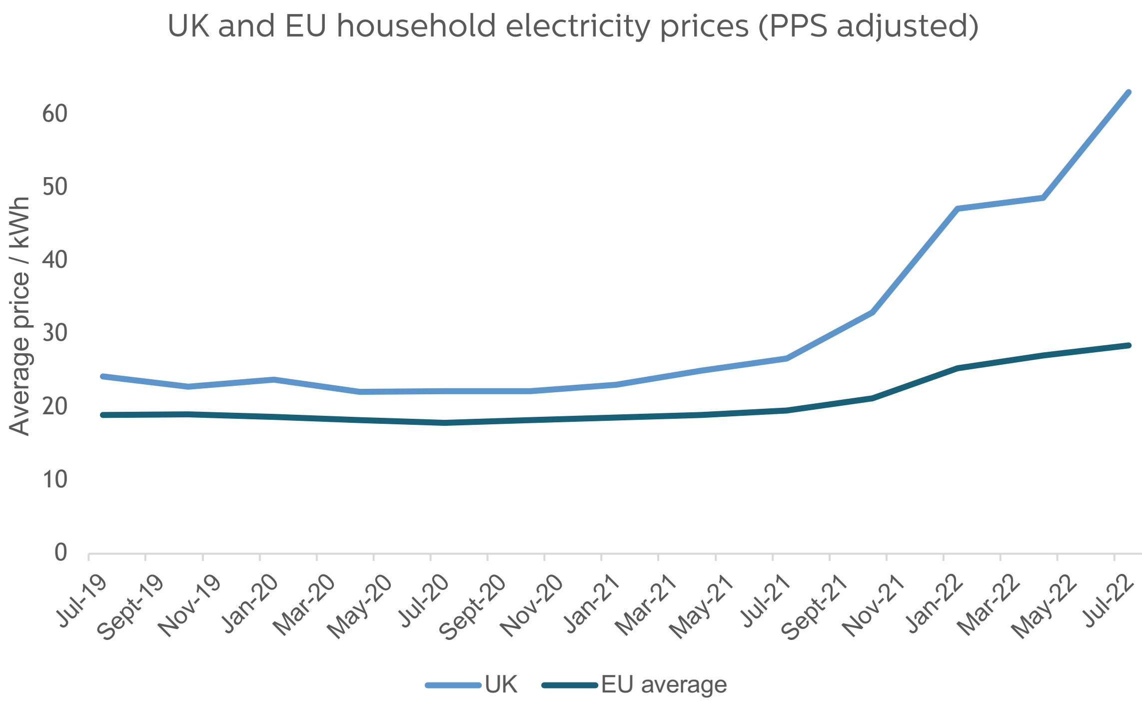

Figure 2: UK and average EU electricity prices in capital cities (PPS adjusted)

Source: [HEPI 2022]

Conventional Energy Storage Technologies

Electrochemical energy storage

For short-term electricity storage, there is a wide range of electrochemical options available, such as lithium-ion and lead-acid batteries. Although a few high-capacity batteries are already in operation to mitigate the intermittency of wind and solar farms, high estimated capital and operational costs of £86 per kWh[*] prevent large-scale deployment. From a life-cycle perspective, the aging of lithium-ion batteries highly degrades their storage and power output capacities, raising several questions about the waste management of their hazardous content[15] [16]. Their limited capacity, self-discharge[17] and failure to satisfy the high-power demand at peak times, make them unsuitable for large-scale, seasonal energy storage[18]. These limitations are reflected in the current and forecasted capacity as the UK's battery storage reached only 1.6 GWh in 2021, with the National Grid estimating 35.4 GWh for the 2030 Leading the Way Scenario. In terms of energy content, the 2030 forecast of 35.4 GWh is nearly 0.2% of the UK's 2021 energy storage capacity[19].

Pumped hydro energy storage

Pumped hydro storage has been a well-established technology since the launch of the first project in 1963, with its main appeal being simplicity and reliability. At times of excess electricity generation, water is pumped from a lower reservoir to an upper one. When electricity demand is at its peak, or renewables do not generate enough power, water is released through turbines to generate electricity. With an estimated efficiency between 70-80%, pumped hydro is the most cost-effective and widespread storage type in the UK. Currently, there are 4 running pumped hydro storage facilities in Scotland and Wales, with generation capacity over 2,800 MW[20] and storage capacity of 25.8 GWh[21]. Pumped hydro, therefore, accounts for 94% of the UK's 27.5 GWh electricity storage capacity[22].

Pumped hydro assets, however, take 5 to 8 years to develop due to their specific geographical requirements, increasing capital costs to a minimum £500 million[23]. The summer of 2022 also showed that filling reservoirs can potentially become more challenging in the future, with droughts getting more widespread due to climate change[24]. Given their frequent cycles, up to sixty a day, and high operational costs, pumped hydro storage assets are more cost-effective for short-term, hourly storage than long-term, seasonal storage[25] [26].

Compressed air energy storage

Working on a similar principle, compressed air energy storage (CAES) facilities pump air into caverns or aquifers when electricity prices are low and release it through a turbine when electricity demand is high. With less space requirement, suitable sites are more widespread than for pumped hydro[27].

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[*] Estimated with 6 Dec 2022 Exchange rate 100 EUR = 86 GBP

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Despite their long service life, acceptable energy efficiency of 40-70%[28], high reliability and reduced environmental effects, there are only few CAES assets worldwide and only one in Europe. This is attributed to their low energy density compared to competing technologies[29]. Higher pressure, and hence temperature in underground storage can decrease operational efficiency and increase the risk of damage[30]. Moreover, similar to pumped hydro, the increased capacity of renewable electricity storage would only decarbonise electrified sectors, disregarding homes and industries which are still highly dependent on natural gas and other fossil fuels.

Thermal storage

Although nearly 11 million homes use intra-day, tank-based heat storage systems, only a few tens of large-scale thermal storage facilities have been deployed in the UK[31]. Despite their low estimated capital cost of £0.3 per kWh[32], their large space requirement and low energy density make them attractive to only a low number of district heating systems. In addition to large hot water vessels, aquifers and boreholes can be utilised as storage, allowing consumers to cool or heat their buildings depending on the season. However, due to lengthy geological investigation, potential leakage and low thermal energy demand[33], manmade vessels are expected to remain the most common thermal storage type, with no alternative to long-term, inter-seasonal storage.

The Role of Hydrogen in the Energy System

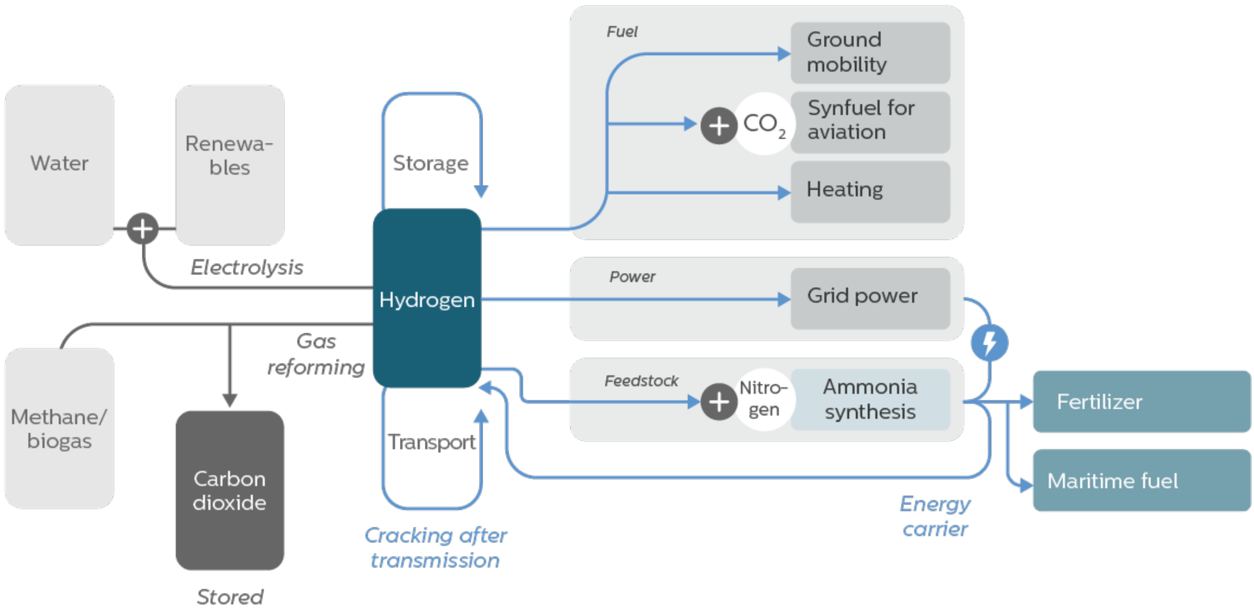
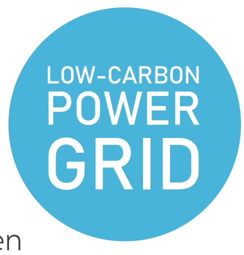


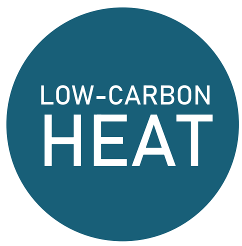
Figure 3: Hydrogen Pathways in the Energy System.

Source: Hydrogen Council 2021

Hydrogen, one of the most versatile energy carriers, can be produced through a number of methods. “Green” hydrogen can be made through the process of electrolysis, producing hydrogen directly from water with renewable electricity and no greenhouse gas emissions. This means that at times of excess low carbon electricity generation, surplus power can be converted to hydrogen and accumulated for later. Use of this hydrogen can largely mitigate the intermittency of wind and solar energy. As a low-carbon alternative, methane and biomethane can also be split into “blue” hydrogen and CO_2 molecules through steam methane reforming and water-gas shift reaction, with carbon emissions and other impurities being captured and stored underground.



This “excess” hydrogen can be stored in short or long-term storage assets until energy demand rises again. To meet peak electricity demand, electricity can then be regenerated using hydrogen-fired Combined Cycle Gas Turbines (CCGT), with no particulate matter or greenhouse gas by-products. According to AFRY’s model, the largest savings in net zero system costs arise when electricity flexibility is met through hydrogen storage and hydrogen CCGTs[34]. This is consistent with the findings of Aurora, suggesting that the total cost of replacing gas-fired peaking plants and installing 10 TWh of hydrogen storage, is up to 82% lower than the merely relying on battery storage[35]. Decarbonising the power grid through hydrogen also improves the carbon savings of all consumers, including those who have already installed heat pumps or purchased battery-electric vehicles.



On a smaller scale, green hydrogen is the only zero-carbon alternative to fuel back-up generators[36], supporting businesses, hospitals and off-grid buildings in the low-carbon transition. In transport, hydrogen fuel cells are used to combine hydrogen and oxygen atoms and power electric vehicles, only producing water and some heat as by-product.

Having the highest gravimetric energy density of all non-nuclear fuels (39.42 kWh/kg)[37], hydrogen does not necessarily have to be converted to electricity to support the low-carbon transition. In its pure form or blended with methane, it is suitable to heat domestic and commercial buildings, whilst also serving as a non-toxic, clean cooking fuel. Therefore, hydrogen storage can balance the seasonal heating fluctuations of not only consumers with electric heating but also ones with hydrogen heating systems.

Hydrogen is a crucial alternative to 'hard-to-electrify' sectors, such as heavy industry, aviation, freight transport and ammonia production. Low-carbon ammonia, produced by reacting low-carbon hydrogen and nitrogen at high temperature and pressure, is vital to decarbonise steelmaking, the maritime sector and fertilizer production[38], an industry which is estimated to ensure the food supply of nearly half of the world's population[39].

As the Government plans to cover the majority of hydrogen demand with domestically produced supply[40], accelerating green hydrogen production and storage will considerably strengthen the UK's energy security by reducing reliance on the volatile global markets. With most of Europe having highly limited access to underground salt layers, the UK's favourable geology, technology and expertise have the potential to create considerable export opportunities to UK businesses[41].

Furthermore, large-scale hydrogen storage capacity is anticipated to stimulate other hydrogen production investments. Extensive storage infrastructure would provide greater assurance to investors of continuous, stable and predictable demand for electrolytic and CCUS enabled hydrogen production as well as related CCUS infrastructure. Storage, acting as a driver of continuous demand and efficient production would remove a number of market barriers for investors, further accelerating hydrogen production and transport developments.

Hydrogen Storage Technologies

1. Short-term and small-scale storage

The first new storage projects to start operations will see low-carbon hydrogen being stored in compressed gas tanks and vessels. Although high-pressure cylinders (200-700 bars) are already being used for ground mobility and microgrids due to the low capital cost of the vessel, they are not suitable on large-scale. Small-scale alternatives with higher volumetric density, like liquid hydrogen in cryogenic tanks, are not cost-competitive because of the energy loss during compression and liquefaction.

For large-scale decarbonisation of the UK economy and seasonal energy storage, high-pressure cylinders will not be sufficient. Britain's decades-long experience in underground gas storage technologies, therefore, will be key to unlock the potential of hydrogen.

2. Salt caverns

There is wide consensus that salt caverns are one of the most cost-effective, efficient and proven ways to store large volumes of hydrogen onshore. With multiple salt caverns having been used to store natural gas, nitrogen and hydrogen since the 1970s, the technology is considered highly mature in the UK[42].

Throughout their use for gas storage, salt caverns have proved to be leakproof, with the only leakage possible through the wells[43]. The inert nature of rocksalt means there is low risk of undesired microbial and chemical reactions affecting the quality of stored hydrogen.

Due to the low temperature of the salt caverns, hydrogen can also be compressed more energy-efficiently than in above ground circumstances. Moreover, the low land and operational costs make salt caverns cheaper than batteries by a factor of 100, costing less than £0.50 per kgH2[*] [44] [45]. Given the strong geomechanical structure of the hydrogen salt caverns, high pressure can be attained with either less cushion gas compared to depleted gas fields, or with brine used instead of cushion gas[46] [47], reaching approximately 100 times higher volumetric energy density than CAES of the same size[48].

[*] Estimated with 6 Dec 2022 Exchange rate 0.6 USD = 0.50 GBP

CASE STUDY – Aldbrough Storage Facility by Equinor and SSE Thermal

Aldbrough Gas Storage facility was commissioned in 2011 and has been providing natural gas storage for the Humber region and beyond since. With its capacity to store up to 30 billion cubic feet of gas, it is currently being investigated how its nine underground salt caverns can be converted to support hydrogen storage, avoiding the long lead times and high capital costs of building new facilities. Equinor and SSE Thermal commissioned a feasibility study in early 2022 to assess the design of the salt caverns for hydrogen storage and the connection to the Humber Low Carbon Pipelines. With an expected storage capacity of 320 GWh, Aldbrough can become the world's largest hydrogen salt cavern facility as early as 2028.

However, salt caverns are not geographically widespread, and their capacity to store hydrogen also varies. For instance, Cheshire Basin can store only half of the volumetric energy density of the Zechstein Basin in the east coast of England due to the differences in salt layers[49]. In addition to being sparsely distributed, salt caverns have limited size as each cavern is circa 1 billion cubic feet in volume in comparison to the Rough Storage Facility's 135.2 billion cubic feet capacity. The construction of new salt caverns is possible, but the cost and development schedule, can discourage initial investments. Building a new facility can take 7 to 10 years, with the leeching of one cavern taking at least a year. Whilst repurposing currently operational salt caverns is quicker, simpler and more cost-effective, full conversion of existing facilities would only provide up to 3 TWh of hydrogen capacity. Lastly, the leeching process may require additional infrastructure to ensure that brine is disposed of in a safe way, not creating environmental damage in freshwater. Although the risk of undesired microbial reactions is low, each specific geological site would have to go under rigorous investigation to fully understand the technical barriers associated with brine and hydrogen contamination.

3. Depleted gas or oil reservoirs

The most suitable option for offshore large-scale hydrogen storage is depleted hydrocarbon fields. These reservoirs are not only sufficient in size, but they also have proved to seal natural gas and oil adequately, with 74% of natural gas already being stored within depleted hydrocarbon fields globally[50]. In contrast to salt caverns, data and research are widely available as these sites have been used for extraction for decades[51]. The existing pipeline infrastructure from the gas fields to processing facilities and the gas grid can also prove crucial to investors as they can considerably reduce capital costs of hydrogen transport. As highlighted by the H21 report[52], converting a depleted gas field can be more cost-effective in terms of cost per unit volume of storage than creating new salt caverns. This, however, highly depends on regional and site-specific circumstances. Furthermore, depleted gas fields are preferred over oil fields as gas may not be trapped by the same seal that held oil back. With oil fields being rich in water and gas as well, the planning process would face further challenges, such as modelling a four-component system.

One potential issue which is frequently raised in relation to porous media is the risk of diffusion given the small diameter of hydrogen molecules compared to methane[53].

However, recent findings suggest that losses from dissolution and diffusion can be minimised to 0.1%[54]. Further investigation, including academia led projects such as the HyStorPor and HyUSPRe, showed no significant risk of hydrogen loss during laboratory testing and numerical modelling[55].

Other concerns and potential challenges are associated with physical, chemical and microbial processes[56]. As gas and oil reservoirs are not as 'inert' as salt caverns, sulphate-reducing bacteria can contaminate the reservoir with hydrogen sulphide. Resolutions for these challenges are currently under investigation, with recent research suggesting no significant risk of geochemical reactions between hydrogen and the minerals in the storage reservoir over the timespan of seasonally stored hydrogen[57] [58].

The higher cushion gas requirement of depleted reservoirs compared to salt caverns can increase capital costs. As hydrogen currently cannot be used as cushion gas due to high cost and potential lack of available volume, research is underway to investigate how alternatives such as methane, CO_2 and N_2 would work as base gas. Whilst regulation does not allow the use of carbon dioxide as cushion gas yet, it has the added benefit of removing a significant volume of carbon emissions from the atmosphere if captured from sources that would otherwise expel the CO_2. With new modelling technology being available, it is possible to predict multicomponent flow behaviour, enabling field conversion design to limit the mixing of the base gas with the working gas. This means that physical processes which have been previously considered potential risk, like 'viscous fingering' and 'gravity override'[59], can be mitigated.

CASE STUDY – Rough Storage Facility by Centrica

Centrica recently announced the reopening of Rough field, the UK's largest natural gas storage facility, with first injections made in September 2022. In the short term, Rough's initial capacity of 30 billion cubic feet will strengthen the UK's energy security by balancing the volatilities of the global natural gas market. With Centrica aiming to redevelop Rough as a 10TWh hydrogen store in the long-term, the UK can soon have direct access to the world's largest hydrogen storage facility. To provide context, 10 TWh of storage capacity is equivalent to approximately 150 average sized salt caverns, each of which would take one year to build. As Rough has favourable geological characteristics such as high temperature, salinity and dryness, risks associated with microbial processes and hydrogen sulphide contamination are generally low. The reservoir is sealed by an 800-metre-thick layer of Zechstein salt formation, and a Bunter Shale and Sandstone overburden, thus providing the necessary geological integrity. Being developed in three 3.3 TWh phases to match the growth of the hydrogen economy, Rough can provide large-scale hydrogen storage as early as 2030. With the long lead time and high capital costs of new salt cavern projects, Rough is currently one of the most cost-effective options in terms of unit volume of storage to meet our hydrogen and carbon reduction ambitions.

It is important to note, however, that both salt caverns and porous media are needed to meet forecasted storage requirements and reach net zero by 2050. Whereas salt caverns are suitable for fast cycle and medium range applications, porous media will strengthen cluster resilience and balance seasonal fluctuation by providing long duration energy storage. Although salt caverns will be critical to support onshore hydrogen storage, repurposing depleted hydrocarbon fields is anticipated to be the most cost-effective option for large-scale offshore storage.

In addition to salt caverns and depleted gas fields, it is also possible to store hydrogen in saline aquifers offshore which provide much larger storage capacity than individual depleted hydrocarbon fields. However, they are geologically less well understood, and the technical and commercial barriers will be higher, therefore we have not considered these methodologies in this report.

	ADVANTAGES	LIMITATIONS
SALT CAVERNS	- Mature technology - Low cushion gas requirement - Leakproof - Relatively low cost - Inert nature	- High CAPEX of new salt caverns - Limited size - Some microbial risk - Long construction time of new caverns - Geographically constrained
DEPLETED GAS FIELDS	- Large storage capacity - Proven seal for methane - Existing infrastructure for H2 and CCUS - Data and research widely available	- Higher cushion gas requirement - Some risk of geochemical and microbial reactions - Geographically constrained

4. Large-scale above ground storage technologies

In a practice known as linepacking, hydrogen can also be stored within the gas transmission and distribution network. Even though the high-pressure pipelines of the National Transmission System have reached the hourly linepack of 4146 GWh natural gas, due to the low volumetric density of hydrogen this same network would be anticipated to store only 25% of this level of energy[60 61].

There are multiple innovative above-ground technologies in the initial research process, with many of them receiving funding under the Long Duration Energy Storage Competition. For instance, EDF's HyDUS (depleted uranium storage) received considerable support from BEIS to use Urenco's depleted uranium for storing hydrogen as uranium hydride (UH3). Besides utilising nuclear waste products, the project can potentially deliver a storage alternative which can reach twice the volumetric density of liquid hydrogen[62]. Like HyDUS, the HEOS project is also investigating metal hydride technology for future long-term storage. Corre Energy in Wales is working on a unique long duration energy system by utilising their patented Carbon280 Hydrilyte™ hydrogen carrier. There is also active research on using ammonia not only as a maritime fuel, but also as a hydrogen carrier. Liquid ammonia, having almost three times higher volumetric density than compressed hydrogen (12.7 MJ/L vs 4.5 MJ/L), can serve as a safe, stable and easy-to-transport energy carrier[63]. Lastly, liquid organic hydrogen carriers (LOHC), in which hydrogen is chemically bonded to a stable organic liquid carrier, are also actively investigated since they are compatible with existing fuel infrastructure.

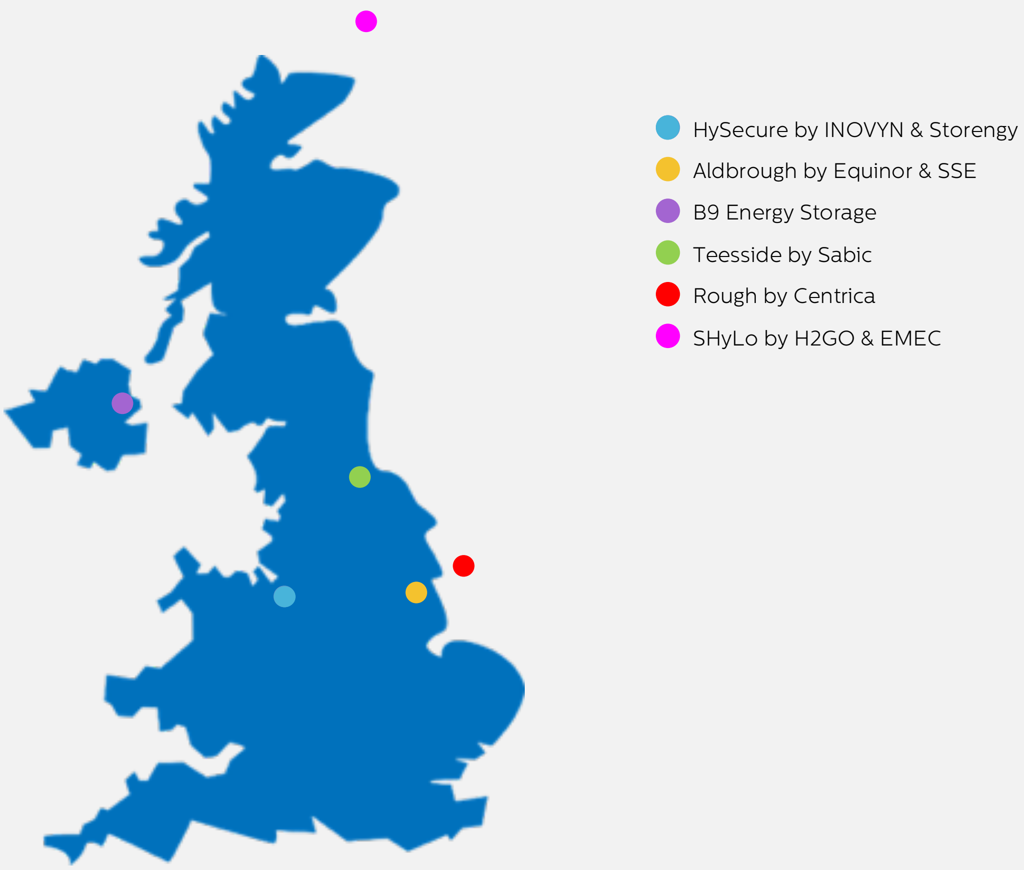


Figure 4: Current Large-scale Hydrogen Storage Projects in the UK

CASE STUDY – SHyLO by H2GO Power

Under the Government's Low Carbon Hydrogen Supply 2 competition, the SHyLO (Solid Hydrogen at Low Pressures) project by H2GO Power secured £4.3 million to develop their innovative storage system in the Orkney Islands. As compressed gas storage can have efficiency limitations and high compression costs in addition to large floor space requirements, H2GO Power's low-pressure solid-state hydrogen storage technology aims to provide a suitable alternative to on-grid and off-grid offtakers.

By removing the need for compression, which is a significant component of operational cost, potential storage savings compared to compressed hydrogen can be increased up to 55%. The levelised cost of hydrogen conversion and storage, therefore, is estimated to be £0.20 per kg[*] by 2028 depending on the number of cycles throughout a reactor's lifetime. Whilst 350 bar cylinders have a storage capacity of 26.1 gram of hydrogen per litre, one H2GO Power unit can store up to 50-100 gram per litre. This is higher than the volumetric density of liquid hydrogen. As hydrogen can be stored at ambient temperatures and pressure, this technology does not only have the potential to reduce costs and increase efficiency, but also to remove key policy and regulatory barriers.

Long and Short-Term Capacity Requirements

In the short-term, small-scale storage assets, such as high-pressure vessels and cylinders, are anticipated to dominate the market. These technologies are mature and already employed for hydrogen buses and refilling stations, due to their low cost at small scale. However, with the UK approaching the 2025 target of 2 GWh, the demand for large-scale storage facilities will grow rapidly.

In terms of long-term requirements, researchers of the University of Edinburgh found that the UK needs 150 TWh of hydrogen storage to fully decarbonise gas[64]. When only heat decarbonisation is considered, this number reduces to 77 TWh, according to Mouli-Castillo *et al.* (2021)[65]. This is not consistent with the H21 North of England report which found that when hydrogen is deployed for power, heat, transport and industry, interseasonal storage requirements are significantly lower compared to a scenario in which hydrogen is used for heat exclusively. According to an AFRY report commissioned by BEIS which estimated hydrogen storage requirement for long duration storage to be between 11.4 TWh and 17.2 TWh, oversizing seasonal hydrogen storage would be a low regret decision, with some utilized at a low rate of cycling. Adding 5TWh additional working volume of hydrogen storage at a capital cost of £2.5bn would give significant extra resilience to the system and help reduce reliance on gas producers for security of supply. The National Grid estimated that 56 TWh of storage is needed for their System

[*] Estimated with 6 Dec 2022 Exchange rate 0.25 USD = 0.20 GBP

Transformation scenario, and 11 TWh under their Consumer Transformation scenario to achieve net-zero by 2050[66]. To put that into perspective, the UK natural gas storage capacity in 2021 was just over 16.5 TWh[67], roughly one quarter of National Grid's 56 TWh figure.

In an initial high-level assessment, Hydrogen UK estimates that 3.4 TWh of large-scale storage capacity is required to be operational by 2030. To support the rapid development of the hydrogen economy, the storage volume could need to be expanded to 9.8 TWh by 2035. These figures are comparable but higher than the capacities found in the three net zero Future Energy Scenarios.

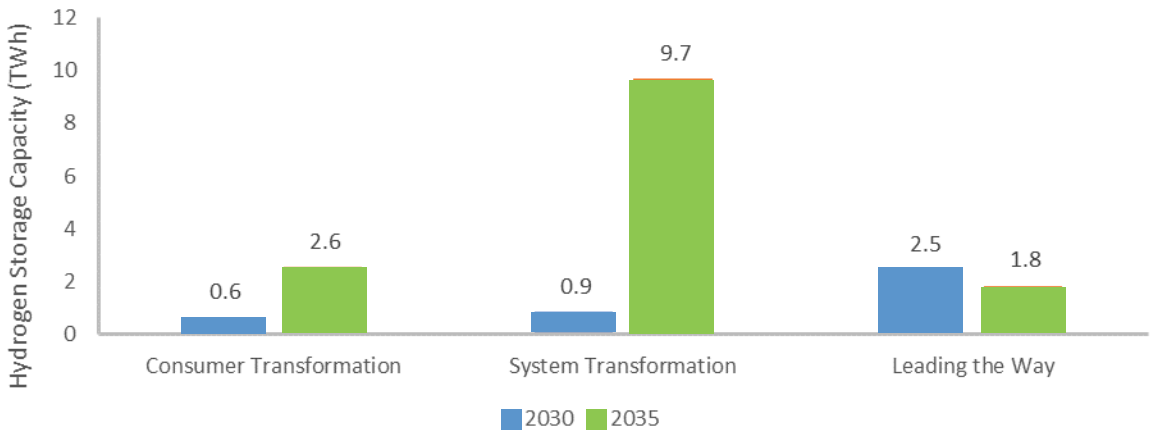


Figure 5. National Grid Future Energy Scenarios Storage Requirements

Assumptions

- Full set of assumptions and data sources can be seen in the annex.
- Supply and demand are equal over the year.
- The year starts with sufficient hydrogen in storage to manage supply and demand side variation.

Hydrogen production

- In 2030, 5 GW of electrolytic production that tracks hourly offshore wind generation 5 GW of CCUS-enabled with a flat production other than maintenance. In 2035 production capacities are estimated using the maximum demands in the Hydrogen Strategy and assuming an even split between electrolytic and CCUS-enabled, this method gives an approximate doubling of capacity from 2030.

- In 2030, all CCUS enabled production is offline at the same time in the high resilience scenario. In the 2030 low resilience scenario and the 2035 scenarios there are two periods where half of CCUS-enabled production is offline.

Hydrogen demand

- Sector demand in 2030 is estimated by apportioning annual production by maximum demand proportions in the hydrogen strategy, other than heat which is capped at 1 TWh. In 2035 the maximum values from the Hydrogen Strategy are used.
- Demand profiles are less granular due to data challenges, assumed flat for period specified for industry, transport and heat e.g. for industry demand is calculated for Q1 and assumed flat for this whole period. Power demand profile uses periods of lower wind generation as a proxy for time periods that require hydrogen power.

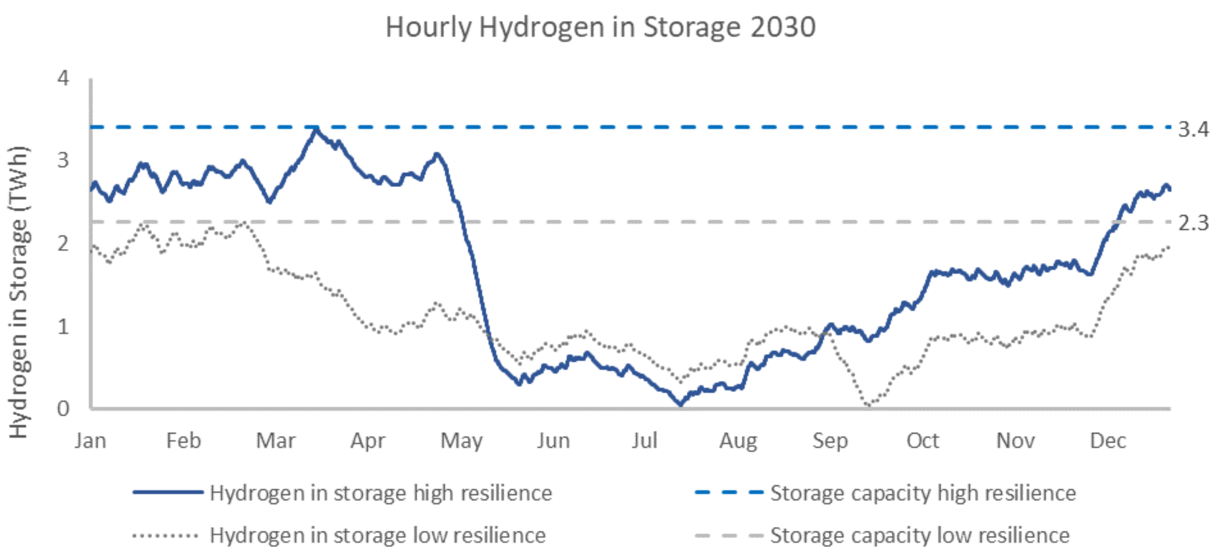


Figure 6. Hourly Hydrogen in Large-scale Storage 2030

This shows that even without significant deployment of hydrogen heating, there are substantial storage requirements by the end of the decade if government hydrogen production targets are going to be met.

This assessment could be improved upon by taking into account more granular demand profiles and considering the timing and scale of CCUS-enabled production downtime in more detail. Additionally, peak heat demand data could be used that reflects requirements for a resilient energy system. While this analysis and FES highlight the need for urgency in developing hydrogen storage, particularly given the long lead times for large-scale storage, more detailed analysis should be undertaken to accurately assess requirements.

Theoretical Storage Capacity of the UK

Fortunately, the UK not only has favourable geographical characteristics but also valuable expertise in underground hydrogen storage. Three elliptical shaped salt caverns in Teesside were the very first globally to be deployed for hydrogen storage in 1972[68].

Although Teesside is the only operational hydrogen salt cavern in the UK, there are several sites which are highly suitable for salt caverns, with an overall estimated capacity of 9 PWh[69]. The Cheshire Basin, the Wessex Basin and the Eastern part of the Zechstein Basin in Yorkshire and County Durham are all suitable onshore sites for new salt cavern construction. The 1600 salt caverns of the Cheshire Basin[70] alone are believed to have a capacity of 284 TWh[71] exceeding the entire predicted UK hydrogen storage demand. The primary advantage of the UK, in contrast with most European countries, is that all salt basins are within 50 km of shore, significantly lowering the cost of construction[72]. One of these costs relates to the waste management of the leaching material, which can get disposed of in salt waters when it cannot be used as feedstock in the chemical industry.

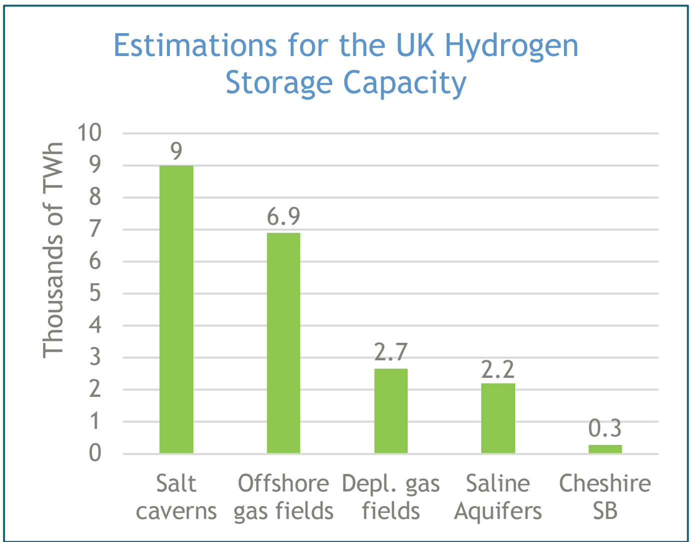


Figure 7: Theoretical Hydrogen Storage Capacity Estimates

Notes:

Salt cavern potential: Offshore and onshore salt cavern potential estimated by Caglayan (2020)
Offshore gas fields.: Hydrogen storage capacity of depleted offshore gas fields estimated by Scafidi et al (2020)
Depl. Gas fields: Hydrogen storage capacity of depleted offshore gas fields estimated by Mouli-Castillo (2021)
Aquafers: Hydrogen storage capacity of UK aquafers estimated by Scafidi et al (2020)
Cheshire Salt Basin: Hydrogen storage capacity of Cheshire Salt Basin estimated by ACT Elegancy Project Report

Offshore gas fields and salt caverns are, however, anticipated to have a greater role in future hydrogen storage. Given favourable geographical characteristics, the UK has access to salt caverns and gas fields in the Eastern Irish Sea as well as the North Sea. Researchers at the University of Edinburgh argue that 6900 and 2200 TWh of hydrogen capacity can be unlocked by investing in offshore gas fields and saline aquafers, respectively[73]. Other methodologies suggest that depleted gas fields might accommodate 2661.9 TWh of hydrogen, still nearly 250 times higher than the 2035 hydrogen storage requirement[*]. In offshore storage sites, higher volumes of hydrogen can be stored due to the lower temperature and higher pressure, resulting in some reductions in operating costs. For instance, the energy density of salt caverns under the North Sea is roughly two times higher than the relatively shallow caverns of the Cheshire Basin[74]. However, construction of offshore salt caverns with current technology remains

[*] Using Hydrogen UK estimate

significantly more expensive than developing onshore ones. Given the amount of ongoing research on offshore hydrogen production, offshore hydrogen storage can potentially further reduce wholesale prices in the future[75]. Considering the significant difference between hydrogen storage requirement and capacity in the UK, it is highly unlikely that hydrogen storage will compromise or take away space from carbon storage or compressed air projects. Given the considerable unutilised gas storage capacity, there is potential for mitigating other European countries' seasonal demand and supply fluctuations as well.

Figure 8: UK Salt Deposits

Source: ETI Report on Hydrogen

Recommendations

The UK's highly favourable geographical characteristics and access to depleted hydrocarbon fields allow us to meet our storage capacity requirements for 2030 and 2035 but the right government support remains critical. To ensure that we maintain the momentum of the hydrogen economy and unlock critical hydrogen infrastructure investments, government action must be taken, with the adequate urgency injected into this process. Hydrogen UK, therefore, recommends the following steps to be taken.

1. Design a regulated business model for large-scale hydrogen storage

To strengthen investor certainty, a business model needs to be designed and implemented for large-scale hydrogen storage as soon as possible. Cap and Floor, Contract for Difference and Regulated Asset Base business models all have the potential to provide investor confidence whilst maintaining value for money. Hydrogen UK's position is that a Cap and Floor business model, having been deployed in the electricity sector successfully for years, is the most suitable to effectively address price and volume risks associated with the growth period of the storage infrastructure. By topping up developers' revenue in weak revenue years, the price floor of the model reduces inter-year revenue variability and makes initial asset financing easier. In strong revenue years, however, the Government would receive the difference between the cap and revenue as a reward for taking on the initial revenue risks. Unlike other regulated approaches, like Regulated Asset Base, the merchant band between the cap and the floor incentivises the storage provider to increase revenue by increasing the volume of storage sold. In contrast to the merchant model of gas storage, the floor would also ensure that UK hydrogen storage capacity stays at an optimal level, strengthening energy security and resilience during times of supply and demand shocks.

This business model, however, does not need to be technology-agnostic. Support under the storage business model should be primarily given to mature technologies, such as salt caverns and depleted gas fields. A route to market for alternative immature storage solutions should be kept open through separate innovation spending, as it has been done under the Longer Duration Energy Storage Demonstration Programme Stream 2.

We see mature underground storage facilities as the primary solution for servicing the need for large-scale hydrogen storage providing seasonal and daily flexibility. However, a diverse suite of storage technologies may be required to service the full range of needs cases. Government could consider a model of stacking different value streams for storage similarly to what is done with electrochemical storage. This will recognise what individual projects are trying to achieve and remove barriers to projects realising their true value to the grid by incentivising factors such as seasonal supply and grid flexibility delivered by hydrogen storage.

2. Launch interim measures before the design of the Storage Business Model

To ensure the UK is to meet 2050 climate targets, it is imperative that large-scale storage investments begin prior to the design of business models by 2025. Suitable interim measures include but are not limited to:

- Actions that financially incentivise early deployment
  - DEVEX and CAPEX support for initial storage projects
  - Introducing a short-term business model until 2025
- Actions that improve investment certainty:
  - Clarifying plans on grey hydrogen phase-out
  - Mandating hydrogen ready boilers from 2026
  - Continued commitment to setting the UK ETS cap in line with Net Zero
  - Clarifying plans on blending and creating a blending framework (like PPAs in electricity)
  - Decision on hydrogen distribution for transport (Hy4Transport)
  - Enabling blue hydrogen by implementing Carbon Capture and Storage
  - Setting a target for hydrogen refuelling stations
  - Increasing emission standards for vehicles
  - Increasing the number of heating trials, including the acceleration of the hydrogen village trial to demonstrate hydrogen heating in practice

3. Create a strategic planning body which facilitates the coordination between network and storage infrastructure projects

Strategic planning will be required to overcome the market barriers with hydrogen storage and so that hydrogen storage can complement the wider energy system. A strategic planner must act independently in the national interest to ensure a level playing field for UK businesses, assessing whole system value of storage projects and complementing the deployment of hydrogen production and its use in heating, power and industry with necessary storage. Being responsible for bringing together views of industry and coordinating deployment of transport and storage infrastructure, this body must maintain cohesion between the strategic planning approach for transport and storage. This role should evolve as market signals become stronger as the market matures and where possible market-led approaches should be allowed to bring forward key smaller-scale storage infrastructure projects.

Annex – Data Tables

Hydrogen Production[76]	2030	2035	Unit
Electrolytic production capacity	5	10.4	GW_{H2}
CCUS Enabled production capacity	5	10.4	GW_{H2}
Total annual hydrogen production	63.9	132.0	TWh

Hydrogen Production Load Factors[77]	Value	Unit
Electrolytic load factor	51	%
CCUS Enabled load factor	95	%

Hydrogen Annual Demand[78]	2030	2035	Unit
Industry	35.7	45.0	TWh
Transport	10.2	45.0	TWh
Heat	1.0	12.0	TWh
Power	17.0	30.0	TWh

Hydrogen Demand Profiles Industry and Transport[79]	Industry	Transport	Unit
Quarter 1	29.6	23.5	%
Quarter 2	22.6	25.6	%
Quarter 3	22.0	26.0	%
Quarter 4	25.8	24.9	%

Heat Demand Profile	Proportion of annual demand	Unit
January	15.2	%
February	13.4	%
March	13.0	%
April	11.3	%
May	5.9	%
June	1.0	%
July	1.0	%
August	1.0	%
September	1.0	%
October	9.4	%
November	12.5	%
December	15.3	%

Power Demand Assumptions	2030	2035	Unit
Generate if wind generation is below % of capacity	75	25	%
Load factor	74	24	%

Hydrogen UK

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